THE COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

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DIRECT TESTIMONY OF

DANNY G. COTE

-- HISTORIC OPERATING PERFORMANCE,
STEEL INFRASTRUCTURE REPLACEMENT PROGRAM,
CAPITAL BUDGETING PROCESS, AND
PLANT ADDITIONS --

IN SUPPORT OF
BAY STATE GAS COMPANY'S
REQUEST FOR INCREASE IN BASE REVENUE
AND OTHER RATE MODIFICATIONS

EXH. BSG/DGC-1

APRIL 27, 2005

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DIRECT TESTIMONY OF DANNY G. COTE

I. INTRODUCTION

Q. Please state your name and business address for the record.

A. My name is Danny G. Cote. My business address is 300 Friberg Parkway, Westborough, MA.

Q. For whom do you work and in what capacity?

A. I am the General Manager of Bay State Gas Company ("Bay State") and Northern Utilities, Inc. ("Northern"). In that capacity, I manage the natural gas distribution operations in Maine, Massachusetts and New Hampshire on behalf of Bay State and Northern.

Q. Please explain.

A. I am accountable for overall leadership and direction for the Operations areas of Bay State and Northern. These responsibilities include oversight of Gas Distribution, Customer Service, Metering, Plants and System Regulation, Logistics, Fleet Maintenance, Facilities and Engineering.

II. PROFESSIONAL QUALIFICATIONS

Q. Please describe your work and educational experience.

A. I graduated from Edward Little High School in Auburn, Maine, then attended the University of Southern Maine ("USM"). I joined the Maine Division of Northern in 1972 and throughout the 1970's held a variety of engineering and operations leadership positions, becoming responsible for Northern's Maine distribution system in 1981. Throughout the 1980's and 90's, I held a number of operations management roles of increasing responsibility for Northern and Bay State, and from 1995 to 1998 served as director of Distribution for Bay State and Northern Utilities. I most recently served as general manager for Bay State's northern region, which includes Bay State's Merrimack Valley service area in Massachusetts, as well as Northern's service areas in Maine and New Hampshire.

Q. Have you testified before this or any other regulatory commission?

A. Yes, I have testified before the Department a number of times in various proceedings. In addition, I have testified before the New Hampshire Public Utilities Commission and the Maine Public Utilities Commission.

Q. Please describe your membership in, or affiliation with, any industry organizations.

A. My industry affiliations include: Chairman of the Board, New England Dig Safe; Chairman of the Northeast Gas Association Operations Management Committee; Chairman, Northeast Gas Association Operator Qualifications Task Force; Voting member of the national American Society Mechanical Engineers B31Q (Operator Qualification) Committee; Past Member, American Gas Association Construction and Maintenance Committee; Member, Society of Gas Operators; Member, New England Guild of Gas Managers.

III. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony today?

A. I describe Bay State's distribution system, its historic operating performance; and its proposed Steel Infrastructure Replacement ("SIR") program. I also describe how Bay State manages its capital budgeting process. Bay State also asked me to help support for the non-discretionary, the revenue producing and the intangible plant additions that have occurred since its last base rate proceeding in 1992. I will also address certain lease, sales and transfers of Bay State assets that have taken place in recent years. Finally, I will discuss the recovery, through rates, of industry-wide research and development funding.

Q. Please summarize your testimony.

A. Section IV provides some background on Bay State's natural gas distribution system. Section V explains Bay State's strong operational history, and I explain why Bay State's ability to control leakage in its system is rapidly being outstripped by the level of deterioration in its unprotected steel mains and services.[1] It is these facilities that require replacement through the SIR program. Bay State's aging unprotected steel facilities are rapidly experiencing corrosion, pitting and rusting. These facilities must now be replaced, in spite of Bay State's strong record of leak surveying, maintenance and repair of these facilities.

In Section VII, I describe Bay State capital budgeting and authorization program.

In Section VIII, I describe Bay State's non-discretionary and revenue producing plant additions, as well as assets that are continuing to be amortized on Bay State's books.

In Section IX, I discuss Other Significant Plant Additions.

In Section X, I discuss certain of the transfer, sale, and lease transactions undertaken since 1992.

In Section XI, I provide information regarding Bay State's request that it recover in rates a Gas Technology Institute ("GTI")-related funding request covering the Operation Technology Development ("OTD") and Environmental Issues Consortium ("EIC"). The research and development activities supported by the

1 The terms "bare steel", "unprotected coated steel" and "unprotected steel," as explained further below, are used interchangeably and all refer to steel pipe without cathodic protection that is susceptible to corrosion.

proposed funding can be reasonably expected to benefit ratepayers and customers directly through increased operational efficiencies, system safety, and improved service.

IV. BACKGROUND OF BAY STATE'S SYSTEM

Q. Please describe Bay State's distribution system.

A. Bay State was incorporated in 1974 from combinations and consolidations over time of many companies, including Rosin Gas Light (incorp. 1859); Attleboro Gas Light (incorp. 1868); Ellerton Mills (incorp. 1895); Chicopee Manufacturing Company (incorp. 1897); Dwight Manufacturing Company (aka Chicopee Gas Works) (incorp. 1897); Attleboro Union Gas Light (incorp. 1899); Chicopee Gas (incorp. 1897) and its successor Chicopee Gas Light (incorp. 1912); South Hadley Gas Company (incorp. 1904/1915); Edison Electric Company of Brockton (incorp. 1915); Easthampton Gas (incorp. 1935); Attleboro Gas Light Company Corporation and its successors (incorp. 1950); Taunton Gas Light and its successors (incorp. 1952); Springfield Gas Light (incorp. 1973); North Bridgewater Gas Light and its successors, Northampton Gas Light (incorp. 1973) and Brockton Gas Light and Brockton-Taunton Gas (incorp. 1974), and Lawrence Gas Company.

Q. What geographic areas does Bay State serve today?

A. Bay State's service territory is three (3) distinct and geographically separate service divisions. Each of those divisions is centered around a major Massachusetts city. They are Brockton, Lawrence and Springfield.

Bay State's distribution infrastructure constitutes the final step in the delivery of natural gas to customers from the producing regions of the Southern United States and Western Canada. Bay State distributes natural gas by taking it from delivery points (or "city gates") along interstate and intrastate pipelines, then transporting it through over 4,700 miles of relatively small-diameter distribution main and over 240,000 services that network underground through cities, towns and neighborhoods in order to meet the demands of end-use customers. Bay State takes legal ownership of the natural gas commodity at the city gate, then steps down the transmission pressure to local distribution pressure, further filters the gas to remove moisture and particulates that may damage Bay State's system, and then increases the amount of odorant known as mercaptan (the "rotten egg smell") to the natural gas before it is put into the distribution system. The gas then goes into the Bay State distribution system where the pressure is often further reduced to delivery pressure in a series of district regulator stations, before being delivered to each customer. Once the gas is delivered on the customer's side of the meter, it is owned by the customer and becomes the responsibility of the customer. In sum, Bay State's distribution system moves relatively small volumes of natural gas at lower pressures over shorter distances to a far greater number of individual users than its interstate pipeline counterparts. Unlike most LDCs in Massachusetts, Bay State has designed a significant portion of its system to operate at 100 pounds per square inch ("psi").

Q. How does Bay State measure the volume of gas used by customers on its distribution system?

A. The natural gas consumed by each customer is measured by on-site meters, which keep track of the volume of natural gas consumed at that metered location. Historically, meters were read manually, meaning meter-reading personnel had to be dispatched to read and record the meters. Beginning in the late 1980's, technology was developed the supported the introduction of automated meter reading systems that were capable of transmitting usage information directly to the Company. The Metscan system was one of the first systems and the Company now employs the Itron system. These systems have resulted in cost savings by reducing the need for manual meter reading, while improving the accuracy and frequency of meter readings.

V. HISTORIC OPERATING PERFORMANCE

Q. Please discuss Bay State's operating performance.

A. Bay State's record for system operation is very strong. See Bay State's response to the November 2004 inquiry from the Department to all LDCs in Massachusetts seeking information regarding operating and compliance issues, including: meter replacements, valve boxes, excess flow valves and leak response and classification. Exh. BSG/DGC-2 (Nov. 9, 2004 Letter, S. Bryant to Hon. P. Afonso).

Q. Does Bay State meet or exceed state and federal requirements for leak surveying?

A Yes. Bay State performs comprehensive leak detection surveys on its mains on an annual basis. Because Bay State performs leak surveys on 100% of its mains each year, it exceeds the requirements of both the U.S. Department of Transportation ("DOT") and this Department's regulations. DOT Part 192.723 requires operators to conduct leakage surveys in business districts at intervals not exceeding fifteen (15) months but at least once per calendar year. In non-business districts, DOT requires leak surveys at intervals not exceeding five (5) years unless the pipes involved are unprotected steel, in which case it is every three (3) years. The Department requires business districts to be surveyed once per year and in areas other than business districts, one every 24-month period.

Q. In what way does Bay State meet or exceed federal requirements for leak backlog/repair?

A. Bay State has a superior record of leak backlog/repair performance. It has been Bay State's long standing practice to repair as many outstanding Type-2 leaks, as defined below, by the end of each calendar year as possible (beginning with the year 2000 through 2004, Bay State has ended each year with 16, 12, 20, 101, and 50 Type-2 leak repairs respectively). As the data demonstrates, Bay State typically ends each year with a reasonably small number of outstanding leaks before the start of the frost cycle in New England. This practice reduces the overall system safety risk by minimizing the number of Type-2 leaks present when the ground is frozen, thus preventing, as much as possible, the likelihood of natural gas migrating under the frost line from a Type-2 leak, thereby placing customers and the public at risk. Bay State's ability to meet or exceed industry performance for leak backlog/repair performance is notable and was maintained favorably in 2003. Since 1993, based on DOT data, Bay State on average ranked in the first quartile (21%) of companies experiencing the fewest number of leaks in backlog at year-end, based on a ranking of Bay State versus regional LDC companies.

Q. How does Bay State classify leaks it detects on its system?

A. Bay State classifies each gas leak according to its severity: Type-1, Type-2 or Type-3. A Type-1 leak is hazardous and requires immediate remediation and repair. A Type-2 gas leak is non-hazardous at the time of detection, but requires a scheduled repair based on the potential for becoming a hazard. A Type-3 gas leak is defined as "non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous." Type-1 and Type-2 leaks must be reported to the DOT, however Type-3 leaks are typically not reported to the DOT in the annual DOT 7100 system reports.

These gas leak classifications are defined in the Gas Piping Technology Committee (GPTC) ANSI Z380.1 "Guide For Gas Transmission and Distribution Piping Systems." The Guide is commonly utilized by gas operators and State pipeline regulators, including the Commonwealth of Massachusetts, as an interpretation of "DOT 192 2003 CFR Title 49, Part 192 Transportation Of Natural And Other Gas By Pipeline: Minimum Federal Safety Standards."

VI. STEEL INFRASTRUCTURE REPLACEMENT ("SIR") PROGRAM

A. <u>Types of Underground Distribution System Piping</u>

Q. What kinds of pipe have been installed in Bay State's system?

A. The system comprises many different types of pipe. From the 1850's to the 1940's, Bay State's predecessor companies installed cast iron pipe throughout the early distribution systems. Cast iron, wrought iron and wood were among the first materials available, and cast iron had the advantage in that it was relatively strong and was easy to install. However, it was vulnerable to breakage from ground movement. When the pipe was buried to typical depths of between 2 and 5 feet, if the soil beneath the pipe or to its side was disturbed and pressure exerted on the pipe, it could crack. Further, each pipe section was not easily joined, so joints were prone to leaks. Finally, it was determined that it was unsuitable for long-distance transportation of gas because it was unable to withstand high pressures.

Q. How did the industry react to the problems present with the use of cast iron?

A. By the 1920's, the industry had adopted steel and wrought iron piping for mains. These were deemed to be stronger than cast iron and able to withstand greater pressure. During this time, bare steel and wrought iron began replacing cast iron pipe as the material of choice when building a natural gas distribution systems. During the post-World War II construction boom, Bay State installed a significant amount of bare steel mains and services. Bare steel is steel pipe that has no exterior coating and has no cathodic protection installed on the pipe. Both exterior coatings and cathodic protection were designed to inhibit corrosion. The use of bare steel and wrought iron was common until the 1950's and 1960's when the industry began to realize that despite its strength, bare steel was subject to corrosion. Bay State installed its last bare steel pipe in the mid-1950's. By 1970, the federal government prohibited new use of bare steel for natural gas distribution system infrastructure.

Q. What did the industry do to combat the problem of corrosion in bare steel?

A. The fact is that all metals corrode as a result of the natural process of chemical interactions with their physical environment. Most commonly, moist soil (which creates an electrolyte) around the pipe causes corrosion. Direct electric current then flows from the metal surface into the electrolyte as the metal ions leave the surface and corrosion takes place. This current flows in the electrolyte to the site where oxygen or water is being reduced. This site is referred to as the cathode or cathodic site. In order to combat corrosion, LDCs began using coated steel. Unprotected coated steel ("UPCS" or "coated steel") refers to steel pipe with an exterior coating (intended to electrically isolate the steel from the surrounding electrolytes in the soil).

Q. Did the use of UPCS solve the problem?

A. No, despite the best efforts of industry, and even though it was for a time an accepted industry standard, unprotected coated steel corroded as well. But for the period from the 1940's through the 1960's, as the industry assessed its options, it was one of just a few alternative piping materials available to meet the public demand for service. By 1970, Bay State had laid its last non-cathodically protected coated steel segment.

Q. What material replaced bare steel and coated steel?

A. It was the coated steel pipe, but it was cathodically protected.

Q. What is "cathodic protection?"

A. Cathodic protection is a procedure by which underground metal pipe is protected against corrosion and deterioration (i.e. rusting and pitting) by applying an electrical current to the pipe. Cathodic protection reduces corrosion by making that surface the cathode and another metal the anode of an electrochemical cell. A primary function of a coating on a cathodically protected pipe is to reduce the surface area of exposed metal on the pipeline, thereby reducing the current necessary to cathodically protect the metal.

At present, the principal methods for mitigating corrosion on underground steel pipelines are external coatings and cathodic protection.

Q. Has the industry further improved the functionality of its piping since the introduction of cathodically protected steel?

A. Yes, it has. Cathodically protected steel has all the advantages of steel in terms of strength and, because of its impressed electrical current, is highly corrosion resistant. However, it is more costly to purchase and install than the next generation pipe – plastic.

Q. What are the benefits of plastic pipe?

A Plastic pipe has proven to be very good for distribution-level pressures. It has strength and flexibility, and, as a result, is generally immune to the stress of ground movement. Plastic is also less costly to purchase and easier to join and install than steel pipe. Plastic does not corrode; and therefore does not require cathodic protection.

Q. Does plastic pipe have any drawbacks?

A. The single significant drawback to plastic is its relative vulnerability to third party damage compared to cast iron or steel. As a result, excavators who do not dig by hand (as required by the DigSafe statute and Department rules) in the vicinity of plastic facilities are very likely to damage them. Cast iron and steel piping have greater tensile strength and thus are somewhat more likely to be able to resist external impact.

Q. How does Bay State install pipe in its underground distribution system?

A. The installation of natural gas distribution pipe requires the excavation of a trench usually under or adjacent to a public street into which the pipe is laid. Installation of natural gas distribution pipe can be a major inconvenience for residents, business owners and municipalities.

Q. How does Bay State keep track of the flow of natural gas through its distribution pipe?

A. Supervisory Control and Data Acquisition (SCADA) systems integrate gas flow control and measurement with other accounting, billing, and contract data to provide a comprehensive measurement and control system. This information is then coupled with a sophisticated computer based flow model of the Bay State system to ensure accurate, timely information on the status of its distribution network.

B. Need for Steel Infrastructure Replacement Program

Q. Why does Bay State need a SIR program?

A. Bay State's distribution system consists of a large amount of unprotected steel mains and services that are subject to corrosion. In recent years, Bay State has determined that there is an increasing number of leaks in areas where unprotected steel is concentrated. The replacement of the unprotected steel will require substantial financial and operational commitment by Bay State. The proposed Steel Infrastructure Replacement ("SIR") Base Rate Adjustment mechanism is intended to compensate Bay State for the extraordinary (i.e., accelerated) capital outlay required to more aggressively manage this increasing problem, and will reduce the regulatory expense of frequent rate increase requests.

Q. Please describe the manner in which Bay State has been addressing the problem of replacing its unprotected steel facilities.

A. Bay State has continuously replaced and retired unprotected steel in its system since the late 1960's and early 1970's. Bay State currently replaces pipe segments following an analysis of the segment's historical leak rate, along with a number of other internally defined risk criteria. Bay State attempts to identify the likely worst performing segments and replaces those each year. These may be wrought or cast iron; they may also be bare steel; they may be Unprotected Coated Steel ("UPCS"). If the base metal is steel and the segment is not cathodically protected, the segment is considered "unprotected steel."

Q. Why is Bay State now so concerned with unprotected steel that it has decided to bring this issue to the Department?

A. Bay State has approximately 583 miles of unprotected steel remaining in its system. In spite of a solid history of replacing unprotected steel mains, Bay State is averaging over 700 corrosion leaks per year in the Bay State system over the past 5 years. This is 3 times the leak rate present 17 years ago despite a significantly reduced inventory of unprotected steel, and is a clear indication that damage and deterioration associated with corrosion is not only becoming more severe, but is accelerating. Brockton alone has experienced nearly a 50% increase in corrosion leaks from 1993 to 2003 (404 to 601), even though Bay State retired or replaced 31% (175 miles) of unprotected steel mains during that same period. The number of leaks per mile for unprotected steel in Brockton exceeds the average number of leaks per mile for the unprotected steel for other regional LDCs, even though Bay State has a better than average leak backlog/repair ratio.

Even with Bay State's continual replacement of the unprotected steel segments that present the most risk each year, the rate of corrosion leaks for unprotected mains has continued to increase. While the miles of unprotected steel have been reduced, the rate of leakage per mile on the remaining unprotected steel facilities has increased. For instance, while Bay State removed almost 700 miles of unprotected steel mains from its system in the last 19 years (1,291 miles in 1985 reduced to 583 miles in 2004), the number of corrosion leaks climbed from 339 in 1985 to 674 in 2004.

At Bay State's historic replacement rate (i.e. the average replacement rate over the last five years), it would take approximately 30 to 40 years to replace the remaining unprotected steel. It would not be prudent to take that long. The acceleration of the corrosion rate of unprotected steel is threatening to outstrip Bay State's ability to cost-effectively address the rate of leakage.

Q. How do you know the cause of these leaks is corrosion and that corrosion is accelerating as opposed to some other cause of leaks?

A. While other causes can create leaks, such as third party damage (e.g. DigSafe violation), outside forces (frost, earthquake), construction defect (damage on pipe during installation), or material defect (faulty manufacturing), I have examined Bay State's leak history by type, and a significant percentage of leaks result from corrosion, at an average cost of $1,021 per corrosion leak repair. See Exh. BSG/DGC-3 (Main Leaks by Type) and Skirtich Exh. BSG/JES-1, Schedule JES-17, page 12 0f 12, (corrosion leak repair costs 2000 – 2003).

Q. Is replacement the only remedy? Is there any other way to retard or arrest the corrosion problem inherent in unprotected steel?

A. No. Corrosion leakage on unprotected steel does not slow down and the rate of leakage will only accelerate as the unprotected steel facilities continue to deteriorate. The first generation bare steel pipe has reached the end of its useful life and must be replaced in a timely, cost-effective manner.

Q. What method of replacement is the most cost-effective?

A. It will be most cost effective to undertake an area-based replacement strategy that will permit the Company to bid the work to contractors competitively, and a contractor to price its bids based on an efficient program implemented by geographic region. This is accomplished by a program predicated on a consistent systematic implementation that targets discrete areas, neighborhood-by-neighborhood, block-by-block, in a geographically continuous fashion. The SIR program will be efficient because construction crews can stage work continuously by shifting the worksite along the pipe being replaced, day in and day out, rather than what is often the case now where crews open and close worksites and relocate labor and equipment across town or across the service territory. The SIR will result in a per foot installation cost less than would be achieved by bidding smaller and more discrete tasks on a per project basis. In addition, there are the public benefits of minimizing disruptions in traffic flow by concentrating work in one section of a municipality.

Q. Where is the corrosion problem most pronounced?

A. Corrosion leakage exists in all of Bay State's system but is particularly severe in the Brockton distribution system, which has the most unprotected steel pipe per mile in Bay State's service areas. Moreover, the Brockton Division requires operating pressure of 100 pounds per square inch ("psi") to meet its public service delivery requirements. The higher operating pressure causes corrosion leaks somewhat more quickly than an unprotected steel system operating at a lower pressure, resulting in more leaks per mile on that system as compared to a lower pressure system of the same age.

Q. Do system operations requirements demand replacement of unprotected steel in Brockton and elsewhere?

A. Yes. Continual system degradation due to unrelenting corrosion will challenge Bay State's ability to meet peak day needs and operate the system safely. Therefore, without this replacement program, Bay State will be forced to accept a high leakage rate and the associated public risks and additional strain on the system when required to meet peak day demands on the system.

Q. What public safety issues are raised?

A Natural gas is an important and clean energy source but it is also a volatile commodity that is unpredictable if it accumulates undetected and then it comes in contact with an ignition source. When it is released openly in the air, it quickly rises and dissipates safely. This type of leak presents a relatively slight risk and the gas can be shut off until repairs are made safely.

Underground leaking of natural gas can have varying consequences. While some natural gas may actually migrate through the soil and escape into open air (unless soil frost or water on the surface prohibits its escape), if there is a path of less resistance, such as along a water or sewer pipeline buried a foot or so above the gas main, it will follow that path. If the path allows the gas to migrate to an enclosed location, such as the basement of a commercial building or residence, and the natural gas accumulates there undetected, the risk increases for a significant leak event where the accumulating gas may be ignited by a spark or electrical charge of some kind, causing an explosion. Loss of life and property are possible in such an event.

Q. Does the accelerating leak problem increase the risk to public safety?

A Yes. Every corrosion leak has the potential to become a risk to public safety. Because the problem is accelerating, the more leaks that occur, the greater the frequency of exposure to the risk that a significant event will follow.

Q. Are you saying Bay State's system is unsafe?

A. No, I'm saying the system, which includes Brockton, Lawrence, and Springfield service areas, is safe right now, as evidenced by our ability to address all Type-1 and Type-2 leaks in a timely fashion. The "system" is comprised of thousands of miles of wrought iron, cast iron, bare steel, coated steel, cathodically-protected steel, and plastic pipe. The material initially at risk is first generation bare steel. Evidence indicates that the corrosion is accelerating, gradually causing more leaks. Because Brockton has proportionally more of this material and operates at higher pressure, the problem is exacerbated in that service area and accordingly, the SIR program addresses Brockton first and Bay State's other service areas in later years. While the system is currently safe, Bay State must, as a prudent operator, address the systemic problem of replacing its unprotected steel facilities. That is why it is implementing the SIR program.

Q. Does that mean that Bay State intends to implement the SIR program whether or not the Department approves the SIR Base Rate Adjustment mechanism proposed in the Bryant (Exh. BSG/SHB-1), Skirtich (Exh. BSG/JES-1), and Ferro (Exh. BSG/JAF-2) testimonies?

A. Yes. Bay State is committed to the SIR program with or without its requested rate recovery mechanism. As I understand Mr. Bryant's testimony, however, Bay State may be unable to earn its allowed rate of return without such a mechanism because of the expected level of capital expenditures to support the accelerated replacement. Nevertheless, my primary concern is the operational integrity of the distribution system and the Company's responsibility to the public and its customers. Bay State is committed to the SIR program.

Q. Can you describe the investment committed to the SIR program?

A. Yes. In 2004, Bay State committed $8 million to its SIR program objectives. In 2005, Bay State has committed to spend $20 million in incremental capital dollars in order to accelerate the replacement of its unprotected steel facilities.

Q. Is this expected to be the continuing level of incremental or accelerated investment in the SIR program?

A. Yes, it is. As Mr. Bryant describes, it is this incremental investment (over and above a base level of bare steel replacement), including overheads and other typically included capitalized amounts, which Bay State seeks to recover in the SIR Base Rate Adjustment mechanism.

C. Operational Design and Field Management of SIR Program

Q. What are the operational and field management requirements of the SIR program?

A. The requirements are fairly straightforward in order to drive the SIR program efficiencies. The SIR program is established within a defined period of 10 to 15 years, in order to produce the maximum efficiencies from the project, reduce the construction cost, minimize public inconvenience and ensure public safety.

Q. How will those efficiencies and reductions in construction cost be achieved through the management of the SIR program?

A. The SIR program will replace all unprotected steel mains and other related facilities, referred to throughout the Company's filing as Eligible Facilities, based on the needs driven by the distribution system, in accordance with the basic tenets of system engineering and planning. Replacements will be determined based on the condition and age of the pipe; geographical proximity; the capacity needs of the area; and, expected growth in system demand requirements. Efficiencies will be maximized and costs minimized by addressing large segments of the system for replacement on a planned, systematic basis, and by concentrating contractor resources and leveraging competitive bidding processes in order to drive down costs of time and materials. By identifying large segments of the system that require attention (through leak rates and repair percentages), including as I've noted, the Brockton portion of the system, Bay State can focus resources and complete full segment replacements and tie-ins in an orderly and predictable fashion. For example, in 2005 the list of municipalities where we will be replacing facilities includes: Attleboro, Duxbury, Franklin, Medway, Brockton, Scituate, Foxboro, Randolph, Stoughton, Hanson, Norton, Taunton, Marshfield, Medfield, Norwell, Walpole, Pembroke, West Bridgewater, East Bridgewater, Hanover, Sharon, Holbrook, Seekonk, Wrentham, Easton, Canton, Northampton, Chicopee, South Hadley, Lawrence, Methuen, and Andover.

Replacing pipe involves cutting of the street surface (if the main underlies a street), excavating a trench a foot or so wider than the pipe to be installed, installing the size and type of new pipe consistent with engineering and operations system design requirements, pressure testing it, proceeding to tie-in the existing or new services and mains into the new line, and finally, once the new line is tied in to all the customers, the old line is abandoned, purged of remaining natural gas, and capped by welding or cementing.

Q. What materials will be used for the newly installed mains?

A. The replacement mains and services are expected to be plastic or cathodically protected steel throughout most of the system.

Q. What do you mean by sizing the pipe to engineering and operations system design requirements?

A. As the Department knows, gas distribution systems are typically planned and designed on a 50-year horizon. Planning dictates that Bay State look ahead for engineering and operations purposes as far as it is able. The choice and size of replacement pipe will take into account the engineering and other requirements of system design.

Q How will the SIR program affect leak repair experience?

A. As reflected in the SIR Base Rate Adjustment mechanism, the program accounts for future reductions in main-related corrosion leak repairs associated with expanded use of plastic or cathodically protected steel throughout the Bay State system. As a result, the Company fully expects to systematically reduce the recent 4-year average level of main corrosion leak repair-related operations and maintenance expenses.[2] Therefore, as explained in the Skirtich (Exh. BSG/JES-1) and the Ferro (Exh. BSG/JAF-2) testimony, the Company proposes a leak repair O&M offset to its SIR program expenditures.

Q. In planning the SIR program, were alternatively defined lengths of the program considered, and why was a 10-15 year period selected?

A. Given the operational objectives and safety imperatives, Bay State decided to replace the facilities in as short a timeframe as possible, i.e. 10-15 years. Customer rate impacts and program implementation feasibility also were taken into account in this decision.

Q. What capitalization trend will the SIR program require?

A. The total cost of the SIR program includes both an historical and incremental or accelerated level of costs to replace all 583 miles of unprotected steel mains and replace or modify 29,520 unprotected steel services and other related facilities, which are connected to these mains, is currently estimated at $305.7 million in 2004 dollars.

Q. What assumptions are behind the cost estimate of $305.7 million?

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2 The Company follows generally accepted accounting principles by capitalizing corrosion leak "repairs" to services, which constitute a full replacement of the given pipe, while booking main leak repairs, which are actual repairs to a given pipe, to O&M.

A. This dollar estimate captures all of the SIR program's Eligible Facilities, including the replacement of unprotected steel mains and services as well as the need to install new tie-overs and relocate affected meters and regulators; assumes a project duration of 15 years; assumes all risers, regulators, and meters will be moved outside in conjunction with unprotected steel replacement; bases all direct costs on 2004 actual costs by category, adjusted to reflect expectations of better contractor prices and advantages of project scale; as noted above, costs are estimated in 2004 dollars; overheads assigned reflect a ratio of Bay State's total annual fixed and variable capital-related overheads to its total annual construction expenditures, which for 2005 is estimated at 31%.

Q. You mention the terms "total SIR program costs" and "incremental or accelerated SIR program costs." Please explain these terms, and how Bay State plans on treating them in relation to its SIR Base Rate Adjustment mechanism.

A. As noted above, the term "total SIR program costs" reflects all the expenses Bay State expects to incur to replace all of the Eligible Facilities (i.e., its unprotected steel infrastructure) that qualify for this program. The key criteria that qualifies an Eligible Facility for the SIR program is that it has to be either an unprotected steel main or unprotected steel service or other related facility tied to an unprotected steel main. The term "incremental or accelerated SIR program costs" reflects the additional SIR program-related costs the Company will incur, over and above a recent four-year historical average, to meet its 10-15 year timetable. It is these incremental or accelerated SIR program costs that the Company proposes to include in its annual SIR Base Rate Adjustment mechanism.

Q. Why is the Company only seeking to include the incremental or accelerated SIR program costs in the SIR Base Rate Adjustment mechanism?

A. As explained in the Bryant Testimony (Exh. BSG/SHB-1), the Company's desire is to only recover the incremental portion of its capital investment associated with the Eligible Facilities.

Q. What direct costs per foot or unit are you estimating for the Eligible Facilities at the current time?

A. I am estimating $60 per foot for mains, $1,310 per service; $946 per service for plastic main tie-overs, and $112 per meter in order to move the meters involved. All the estimates are set out on Exh. BSG/DGC-5.

Q. Do you consider this to be a material operational expense for Bay State?

A. Yes. Moreover, the program itself is completely non-discretionary. Each replaced facility will be a material, non-discretionary, non-revenue producing replacement that must be undertaken to ensure the integrity of the operating system, maintain system reliability and preserve public safety.

Q. How will the Department be able to assure itself that Bay State's construction expenses associated with the SIR Base Rate Adjustment will be known and measurable and reasonable?

A. Bay State only proposes to recover the incremental SIR costs that are known and measurable and reasonable in amount. Therefore, Bay State recommends, as part of its annual SIR Base Rate Adjustment review process, that the Department have the opportunity to audit Bay State's program costs included in any SIR Base Rate adjustment filing. For this purpose, Bay State proposes a Capital Expense Tracking ("CET") procedure, created to identify and provide the necessary support for the SIR program in a formal audit process. Exh. BSG/DGC-6 (Capital Expense Tracking). Because the filing with the Department will be made after the conclusion of a construction program year, the investment will be known and measurable. The Department will have the opportunity to confirm the replacements were prudently undertaken and the costs reasonably incurred. The CET outlines the process flows to be followed for the SIR program, along with a Task Responsibility Matrix.

Q. Will the CET help the Department ensure all the requisite information is provided and easily reviewable?

A. Yes. The CET provides a Documentation Responsibility Matrix that will ensure the appropriate pre and post construction evaluations are completed and the necessary documentation of these evaluations are prepared before being filed with the Department. Each project segment under the SIR program will be accompanied by a CET SIR project dossier, created to provide all necessary analysis for the project, from estimation to completion.

D. Benefits of SIR Program

Q. What are the benefits of the SIR program, as compared with the Company's historical steel replacement program?

A. For municipalities and state highway departments, the SIR program provides a systematic and predictable schedule of construction activities and a minimalization of disruption to traffic, roads and highways. Greater continuity of service is also assured than if the program were administered on an opportunistic basis, which is how the Company currently addresses the segments of the distribution system that require replacement.

Q. Please be specific about the community awareness benefits of the SIR program.

A. Under the proposed program, Bay State will be able to sectionalize the system based on the worst performing areas and target replacements by neighborhood and town. During the winter and early spring preceding each construction season, Bay State will meet with municipal and DOT officials in the affected towns and cities from the departments of public works, to mayor's offices, to state highway engineers, to other important contacts for community outreach. It is Bay State's intent to work in concert with the municipalities to achieve this end. The Company will explain the program, discuss the planned reconstruction, and work in close coordination with our Communications Department. In advance of construction in each locale, we will mail letters to both customers and other residents along each affected street and place ads in local newspapers advising citizens of the purpose for any temporary disruption and inconvenience. With a concentration of resources, we expect to replace, on average, 500 feet of unprotected steel main per day, using a geographic approach so that contractors are not forced to constantly close sites and remobilize to a new location, but rather are able to concentrate work in one area.

Q. What are the cost benefits of the SIR program?

A. By commencing a systematic geographic approach to replacement that integrates Bay State SIR program work with State and municipal improvements, costs will be minimized. Bay State will be able, through competitive bidding, to secure long-term, lower unit cost contracts with various utility installation contractors. Bay State will be also able to purchase larger quantities of construction materials by competitive bidding, resulting in lower cost, long-term contracts. By these means, I expect Bay State will have substantially lower capital and system O&M costs over time due to the reduced construction costs and the avoided O&M costs that otherwise would be associated with accelerated leak rates.

Q. What benefits inure to the public from Bay State's SIR program?

A. Bay State will remove deteriorating portions of its system and enhance the safety of its system by ensuring replacement of facilities with new, longer lasting and safer materials. Its system will continue to be able to provide deliverability at its Maximum Allowable Operating Pressure ("MAOP"). The public will receive better service and less interruptions. This is an important program and Bay State seeks the Department's approval of it for all the reasons stated.

VII. CAPITAL BUDGETING PROCESSES

Q. Please explain the purpose of this section.

A. This section explains the process by which Bay State ensures appropriate analyses are undertaken for capital projects.

Q. Please describe the expenditures that fall under Bay State's capital expenditure policy.

A. Bay State's capital expenditure and budgeting policy applies to all spending authorizations for capital expenditures for the Company. A capital expenditure is defined as the purchase or installation of an asset exceeding $1,000 in value with a useful life of more than one year. This includes items such as hand tools, computer equipment, office furniture, facility replacement, and metering and regulating equipment. Any main replacement over 10 feet, regardless of cost, is considered a capital activity. These procedures are followed before, during and after a capital project to assure the construction activity or purchase was justified, properly approved, managed properly and results in benefits to Bay State's customers. The authorization process provides the classes of capital that can be spent (betterment, new business, support services, etc.) in a manner consistent with Bay State's goal as a prudent operator. It establishes the project information requirements to be elicited for each budget request. It explains the cost-benefit analysis expected.

Q. What cost benefit or needs analysis is included in the Bay State Capital Work Order policy?

A. A cost-benefit or needs analysis may include the following: (1) an explanation of the need for the project, including the results of any technical evaluation performed, (2) a discussion of the prioritization of this capital work order relative to other Bay State needs, (3) a description of the functional requirements to be met, (4) a description of the additional or changed system capability that should be achieved and (5) a description of the alternatives considered (e.g. up-rate, abandon not replace, install pipe in another location, increase or decrease the scope of the project, negotiations with DOT or municipality, etc.).

Q. What is the scope of the Bay State Capital Authorization policy?

A. Bay State's Capital Authorization policy applies to all capital expenditures and is a guide to administering capital spending. It describes the processes for managing capital spending, from estimating to establishing the capital authorization, to gaining specific budget approval to ensuring compliance with authorization requirements for budget variances.

Q. When was the policy created?

A. It was approved by Bay State management in 2005.

Q. What is the purpose of the policy being reissued in 2005?

A. As a result of preparing for this filing, Bay State investigated both past investments and its ability to support the SIR program audit requirements. It determined that improvement could be made with regard to estimating initial project costs, tracking changes during construction, and documenting variances after the completion of construction. The Capital Authorization Handbook was developed, which now has been the subject of internal training for the technical, engineering, budgeting and field operations employees, and will assist in ensuring that every appropriate record is maintained.

Q. Describe the capital expenditure process.

A. Projects may initiate from sales, new business, engineering, notifications of municipal improvements, code compliance or system reliability requirements. Therefore, the first step is to estimate the cost of the project. Bay State uses estimating software that was created by its engineers and is shared among the divisions. The estimating process involves defining the project's limitations to establish which departments of the company are involved. The Sales department may define the length of the main extension to a new customer; Engineering must size the facility to insure adequate capacity and or the necessary length of replacement; the Construction department must coordinate the project with the appropriate state or municipal officials including the location of the facility in the public Right Of Way ("ROW") and the required restoration. If this work is being done in response to municipal or state road reconstruction, then the Construction department will also coordinate the work with that of the designated highway contractor.

Q. What is next in the process?

A. All jobs are evaluated by the Engineering department, which must review the proposed project in the context of its impact on the entire distribution system. This step assures the pipe type, diameter, tie-ins, and related construction are taken into consideration. Engineering or Construction Operations inspects the site to make a site evaluation with regard to pavement disruption and restoration, impediments such as streams, bridges, culverts, and ledge. The site visit also ensures that other factors are included in the estimate, such as the requirements for a state highway crossing.

After the Engineering or Construction Operations groups conclude their site visit, the Construction department inputs the gathered field data into the estimating program. If an environmental permit or other regulatory approval is required, that cost would be added to the program. Contractor bid proposals, material costs and overheads are also included.

Q. Does that estimate then become the capital authorization?

A. Not yet. After the estimate is determined, either the Resource Planning or Engineering departments assign a Project Identification number to each estimate on the Construction Authorization Form, referred to above. Then a project description is added describing the need for the project. In addition to providing particulars about the project, the construction authorization should also specify the amount, diameter and type of facilities to be added, and the facilities expected to be retired. Engineering will then circulate the form for signatures and approvals. The formulation of a capital expenditure package then begins.

Q. Who must approve the capital authorization?

A. The required approvals vary by type of project and the estimated cost of the project. However, the form clearly identifies who must approve. Every project must commence in the year in which the estimate is prepared. If the project slips to the next year, the capital authorization, estimate and related project identification number are each canceled and void. This protects the integrity of the budget process. In such cases, the project must be re-estimated and a new capital authorization prepared.

Q. What happens if the project commences or is about to commence, an circumstances change that indicate the project may be likely to exceed the approved capital authorization?

A. In such circumstances, where the variance has been identified as greater than 10% (or $50,000) from the original approved amount, a variance authorization is prepared. The variance is quite necessarily a re-approval of the budget according to the approval limits applicable to the new amount. Once a project is completed, a comparison of the project estimate and the actual construction costs will be obtained by Bay State's Work Order Management System ("WOMS"). The records associated with the capital authorization, i.e. the capital authorization package, are to be retained for the useful life of the asset at the location of the field office responsible for the project.

Q. Is this authorization required for non-main-related capital expenditures?

A. The process is similar, but a Support Services Capital Authorization is required instead.

Q. Does this authorization apply to large projects, such as those over $250,000?

A. No. Any capital expenditure in excess of $250,000 requires the submission of a specific budget in compliance with the Capital Approval Policy. The business case elements for such capital investment document the strategic, financial, operational, and legal/regulatory support of the project. It identifies the financial indicators: capital, net present value, internal rate of return, and expected residual value. It includes a narrative describing the project for management and explaining the reasoning and analysis that supports the approval of the budgetary funding. It provides a study of the economic implications of the project to be included, and contain both financial narrative and expected key results. It assesses attendant risks and outcome criteria.

Q. Does this authorization track hold true for information technology ("IT") projects?

A. Yes. IT investments also go through a similarly rigorous evaluation process. However, while Main Capital Authorizations and Support Services Capital Authorizations (excluding IT investments) are reviewed and processed through engineering/operations, all IT projects must go through a review process within the Nisource Corporate Services Company Information Technology Department for prioritization and ranking.

VIII. PLANT ADDITIONS

Q. Please describe the purpose of your testimony in this section.

A. It has been 13 years since the Department has had the opportunity to examine Bay State's rate base and I will address Bay State's gas plant investments since its last base rate case. During that time, the Department's standards for documenting the reasonableness of rate base additions has evolved. Also during that period of time, Bay State expended more than a half a billion dollars, $513,234,784, in gas utility gross plant additions. The asset category – Mains – accounted for $163,191,824 or 31.9% of the total. The asset category – Services – accounted for $120,895,159 or 23.6% of the total. The asset category – Miscellaneous Intangible Plant Additions – accounted for $54,198,875 or 10.6% of total gross plant additions. The remaining balance of the total gross plant additions made between 1992 and 2004 - $174,220,926 – or 33.9%, are associated with the other remaining plant accounts. See Exh. BSG/DGC-7.

Q. What are the Department's standards for recovery of plant additions?

A. A utility must undertake a cost benefit or needs analysis, especially in the case of large, multi-year projects, and demonstrate that cost containment measures were undertaken, to support inclusion of non-discretionary plant in rate base. For mains projects in particular, a demonstration of the cause of any cost overrun, accompanied by evidence of the utility's vigilant containment of cost, is paramount.

For revenue producing plant additions, the Department requires that a benefit/ cost analysis with pre- and post-construction internal rates of return ("IRR") be calculated. These analyses can assist the Department in determining whether it was reasonable for the company to commence the project based on the IRR calculated at the time, and whether the company prudently continued with the project if and when it appeared that the costs incurred no longer supported the initial IRR.

Q. How has Bay State presented its gross plant additions in the Company's proposed rate base for the Department's review?

A. Consistent with recent policies of the Department, Bay State has conducted an complete examination of its plant files to provide documentary support for the gross plant additions since its last base rate case, including both non-discretionary and revenue producing additions in excess of $100,000.

A. Non-Discretionary Plant Additions

Q. What analysis was completed to justify gross plant additions of a non-discretionary nature since 1992?

A. Bay State has identified 107 individual non-discretionary projects closed to plant Account 367 (Mains) between year end 1991 and year-end 2004, the test year, which were greater than $100,000. Exh. BSG/DGC-8. For each of these projects, Bay State provides the Department with a summary that includes a variety of information, including the year the project was undertaken, the name of the project, the location of the project (e.g. city/town), a description of the project location (e.g. street name), the actual indirect and direct (total) main costs, the actual direct main costs, the comparative estimated direct main cost, the dollar amount of any variance between estimated and actual direct cost, and the percentage of how much the actual cost deviated from the initial or recorded estimate. In addition to a detailed description of the type of project and purpose, for each project in which there was a cost over-run or budget error, I provide the basis for that difference. This information was contained in closing reports and other plant records.

Q. Does Exhibit BSG/DGC-8 contains detailed plant records and other information related to every one of these 107 projects over $100,000?

A. No. Because of the volume of material supporting each of these projects (totaling 6 storage boxes of background material), my summaries are confined to variances and asserted cost overruns that are greater than 10%, which could be deemed to be material.

Q. Is a cost overrun of 10% by your definition a "material" variance?

A. Not necessarily. Many construction contracts contain contingencies assumed of up to 25% or more, depending on the activity. For the purposes of this analysis, the comparison was made from estimated direct cost to actual direct cost. No "contingencies" are subsumed in those numbers, and once examined, each variance is quite justifiable.

Q. Where a greater than 10% variance is identified, how have you analyzed the project backup?

A. Where I was able, I provide a narrative describing the Project Engineer and Construction department justifications for each variance noted.

B. Revenue Producing Plant

Q. What analysis was completed to justify gross plant additions of a revenue producing, discretionary nature since 1992?

A. Bay State has identified 17 individual revenue producing discretionary projects closed to plant Account 367 (Mains) between year-end 1991 and year-end 2004, the test year, which were greater than $100,000. Exh. BSG/DGC-9. This information was contained in closing reports and other plant records and information.

Q. Has Bay State any evidence of internally-produced IRR contemporaneous with these projects?

A. Over the years, Bay State undertook several initiatives to improve the revenue producing evaluation process, which resulted in changes being made to input calculations (e.g., O&M costs per customer, marginal capital costs and the like), project parameters (e.g., project life projection), and internal hurdle rates (e.g., weighted average cost of capital and risk-adjusted discount rates). In 1998, Bay State undertook an initiative to maximize profitable growth. In 1999, Bay State reviewed and adjusted the maximize profitable growth analysis. In 2002, Bay

State examined and implemented a process to apply risk adjusted discount rates. For this reason, pre-construction and post-construction IRRs are comparable, but not always apples to apples. Understandably, Bay State was internally reacting to forward-looking business prospects that tended to modify its IRR calculations for business purposes. However, for revenue producing discretionary projects the actual cost (with limited exception) were in-line with expectation.

Q. What information do you have relative to IRR's for pre- and post-construction of revenue producing projects?

A. My analysis summary is contained in Exh. BSG/DGC-9 (Revenue Producing Projects (Account 367)). For each of these projects, Bay State provides the Department with a summary that includes a variety of information, including the year the project was commenced, the Project ID and location description, the pre- and post- IRR calculations, comments applicable to the project, particularly with regard to cost variances, the estimated cost of the project, and the actual final cost.

C. Non-Discretionary Plant Additions Other than Acct 367, 303

Q. What analysis was completed to justify gross plant additions of a non-discretionary nature that were neither Mains (Account 367) nor Miscellaneous Intangible Plant (Account 303) since 1992?

A. Bay State has identified 40 individual non-discretionary projects closed to plant accounts other than Account 367 (Mains) and Account 303 (Misc. Intangible Plant) between year-end 1991 and year-end 2004, the test year, which were greater than $100,000. Exh. BSG/DGC-10. Bay State includes in its proposed rate base the net plant amounts associated with gross plant additions for non-discretionary capital expenditures necessary for Bay State's natural gas operations, such as LNG facility purchases, capital upgrades to facilities (repiping, perlite installation; liquefaction equipment; regulator equipment), odorant storage; construction of regulators, filters and control lines. See Exh. BSG/DGC-10. Supported by this exhibit as well are the categories of capitalized office and communications equipment that are required for Bay State to administer its general, managerial, customer support, and operations functions.

D. Intangible Plant

Q. What additions are included in intangible plant?

A. First my disclaimer. While I am familiar with information technology, I am not a technology expert and am prepared only to introduce and support the basic concepts, cost-benefit, and used and useful requirements under this category. Should the Department require particular details that go significantly beyond that presented here, I may rely upon other witnesses who specialize in information technology to provide the detail that may be required.

Nevertheless, generally this category includes information technology and other technology investments that support the efficiency of Bay State's administration, finance, management and operational processes. It also includes capitalized organization costs.

Q. Please describe the technology investments included.

A. As shown on Exh. BSG/DGC-11, Bay State's Miscellaneous Intangible Plant additions (i.e., Account 303) includes SCADA software, EASy billing system requirements, WOMS enhancement, Voice Mail, Client Server networking, Voice Recording for customer service enhancement, and various corporate services additions. Each of these technology functions is currently assisting Bay State in meeting its customer needs.

Q. Can you detail the technology that assists in operational and system management requirements?

A. Yes. For example, SCADA provides real time monitoring and control of the distribution system. The EASy system is an off-system gas management application that captures gas contracts, trading, capacity release, storage, scheduling, and accounting associated with upstream pipeline capacity. Gas nominations are scheduled through EASy, electronically submitted and confirmed with pipelines via electronic database interaction processing. Transportation capacity, operational balancing agreements, storage activity and inventories are monitored and managed through EASy. While I've provided detail on two of the systems, each of the systems is in service providing valuable efficiency-enhancing benefits to the Company and its customers.

Q. Are you aware of technology and process improvements added by Bay State that have assisted and improved customer service?

A. Yes. In addition to the Customer Information System (added in late 1999 and discussed below), Bay State installed the Panagon bill image viewing system for Customer Service Representatives ("CSR") in mid 2002; the CallAid CSR on-line knowledgebase; improved IVR in April 2003; electronic fax capability; Geneysis CTI, to permit information to be relayed to active CSRs through screen pops; TargetVision monitors to relay to CSRs current popular news and internal NiSource information; Call Recording (NICE) technologies, automated call back system, and web self serve functionality.

Q. What review process is conducted before an IT capital project is undertaken?

A. As described above, a significant review process is undertaken. All projects proposed in a budget year are critically reviewed and are prioritized as Priority 0 through Priority 3, with Priority 0 being mandatory or of the highest priority.

Q. Who is responsible for reviewing and assessing the reasonableness of all IT capital expenditures?

A. NCSC IT Directors review all IT capital projects. NiSource's Chief Information Officer reviews all IT capital projects exceeding $100,000.

Q. What support is required?

A. All IT projects that are greater than $300,000 and that have gone through the IT review process and designated as Priority 0 (or high priority) are required to be supported by a complete business case analysis. The NCSC Financial Planning department reviews all business cases before approving a budget for an IT project. The business case is comprised of five sections: Project Description & Fact Sheet, Impact Analysis and Dependencies, Economic Analysis, Risk Analysis, Benefit Justification, and Signature Approvals. The Economic Analysis section consists of a package of cost estimation worksheets and a financial model that calculates several financial metrics such as an IRR, Net Present Value (NPV), and Net Operating Profit After Tax (NOPAT) for both a worst case and a best case scenario. Business case development efforts are supported with project management training material, templates, guidelines and approval limits information accessible to each employee through the NiSource intranet site.

IX. OTHER SIGNIFICANT PLANT ADDITIONS

A. Masspower / Monson & Palmer Expansion project

Q. What was Bay State's first significant plant addition since the last base rate filing?

A. Over a two-year period, from 1992 to 1994, Bay State constructed two distribution lines that began in the town of Monson to serve the Masspower generating station and the Towns of Monson and Palmer (thus became known as the Masspower / Monson & Palmer Expansion project).

Q. Please explain what the project entailed, what customers are being served and the significant project dates and milestones.

A. In 1987, Bay State informed the Department of its interest in installing a main to serve the communities of Monson and Palmer, in the event a line was built to serve Masspower. Bay State conducted extensive financial analyses to determine that the expansion project was economically feasible under multiple scenarios.

Masspower is an electric generating station that commenced commercial operation in July of 1993. It is a 267 megawatt combined-cycle cogeneration facility fueled by natural gas. For years, it generated and sold electricity to serve the needs of electric company purchasers such as Boston Edison Company, Commonwealth Electric Company and the Massachusetts Municipal Wholesale Electric Company (MMWEC). The steam generated by the station was sold under a process-requirements contract to Solutia, Inc., located on its grounds. Building facilities to serve Masspower gave Bay State the ability to bring natural gas distribution service to Monson and Palmer. In that same year, Bay State met with and received permission from the Towns to serve them. Shortly thereafter, in July of 1987, Bay State received Department approval to serve the communities of Monson and Palmer. In 1990, Bay State received approval from the Massachusetts Energy Facilities Siting Council. In 1990 and 1991, Bay State applied for and received the required local, state and federal permits to proceed with the project.

In 1992, construction began on the Masspower and Monson & Palmer Expansion project. The Expansion project provided for Bay State to run two extension lines to serve the Masspower generating facility in Palmer and "a to be constructed" distribution system serving customers in the towns of Monson and Palmer. The lines constructed by Bay State, which took two years to build, began in the town of Monson (thus became known as the Masspower / Monson & Palmer Expansion project).

One portion of the construction was known as the "Main Line." The Main Line construction consisted of laying 18.6 miles of a 16" high-pressure steel line originally to serve the needs of the Masspower facility, and subsequently has been used to also serve MMWEC. The line runs from the Tennessee Gas Pipeline interconnect in Monson to the Masspower facility, located in the Indian Orchard section of Springfield, and serves the MMWEC facility in Ludlow, off an interconnection built and paid for by MMWEC.

The second portion of the construction is known as the "Distribution Line," which consisted of the simultaneous placement of a 4" plastic pipe, along side of, and at the same depth and in the same trench as, the 16" Main Line. This system runs 22 miles in total, through the towns of Monson, Palmer and Wilbraham, in order to serve Bay State's Monson-Palmer distribution systems. Finally, the project included a gate station in Monson to take deliveries off of the Tennessee Gas Pipeline. These lines were placed in service in a two-year period, from late 1992 through 1994.

Beginning in 1992, as originally planned, Bay State has been constructing laterals off of the 4" Distribution Line to serve customers in the Town of Monson and the Town of Palmer. As of December 2004, Bay State is serving over 190 residential customers and 90 Commercial & Industrial customers from the 4" Distribution Line. Between 1992 and 1994, Bay State constructed several significant laterals known as the Ware Street, Sykes Road, Park Street and Palmer Street lines off of the 4" Distribution Line.

Q. What was the estimated cost to serve Masspower and customers in the Towns of Monson and Palmer?

A. The project was initially estimated at $15,530,000 for costs to be incurred in FY1992 and FY1993. This included $13,723,500 for costs estimated to construct the Main Line and $1,806,500 for costs estimated to construct the Distribution Line. Preliminary engineering costs prior to FY 1992 of $1,100,000 and expected AFUDC for FY 1992 of $533,000, were added to result in a estimated total costs for the two lines totaling $17,163,000. In December 1992, it was determined that an additional $3.5 million was necessary to build the project.

The variance was deemed to be the result of unusual and excessive construction requirements and demands imposed by the Commonwealth of Massachusetts (DPW and Turnpike Authority), as well as local municipalities. Examples were permitting requirements that mandated wider than typical trenching and therefore, more expansive asphalt patches; removal of spoils in favor of special backfill materials; installation of temporary asphalt patches which later had to be destroyed and repatched for permanence; and saw cutting of both original roadway and any subsequent re-asphalting. More than 10 miles of the project were located in or along state highways. In Monson, Palmer and Ludlow, similar restrictions were placed on Bay State's local construction work by those municipalities.

Q. What was the actual cost to serve Masspower and customers in the Town of Monson and Palmer?

A. The gross plant investment by Bay State, between 1992 and 1994 was $22,448,367 for the 16" Main Line and 4" Distribution Line with $6,407,604 in accumulated depreciation for a net plant total of $16,042,396. In addition to the Main Line and Distribution Line, Bay State has made from 1992 to 2004, gross plant investments of $3,274,027 with $933,996 in accumulated depreciation for a net plan total of $2,199,676 for laterals off the 4" Distribution Line. The total gross plant and net plant amounts for the16" Main Line, 4" Distribution Line and Distribution Laterals is $25,722,394 and $18,380,794, respectively.

Q. What has the project contributed to Bay State's net operating income and return on rate base?

A. In 2004, the 16" Main Line, 4" Distribution Line and Distribution Laterals plant provided net operating income of $1,231,489 and yielded a return of 9.44% compared to a Weighted Average Cost of Capital ("WACC") of 8.41%.

B. <u>CIS Conversion</u>

Q. What gross plant amount is requested for inclusion in the Company's rate base related to Bay State's conversion of its customer information system ("CIS")?

A. Bay State seeks to include $23,818,571 worth of gross plant in rate base associated with the CIS constructed and put into service predominantly in 1999 in order to meet Y2K requirements. However, additional capitalized enhancements to the CIS, which are reflected in the above amount, were added through 2003.

Q. What is the justification for the 1998-1999 replacement of Bay State's CIS?

A. As described in Exh. BSG/DGC-11, the CIS was installed for Bay State in November 1999 to meet the mandates of Y2K compliance. The previous CIS, a legacy system, was exceptionally difficult to upgrade for any purpose and posed a threat to the integrity and continuity of Bay State's operations and administration in the face of the Y2K concerns.

Q. How does the new CIS meet Bay State's requirements to fulfill the service needs of its customers?

A. The CIS installed and active since 1999 is a broad-based customer information system that supports the collection, processing, storage and retrieval of customer service data for Bay State's 285,000 customers and those of Northern's 50,000 customers. The system integrates information exchange and retrieval for numerous operational activities that are part of the customer service requirements.

The logic contained in the CIS supports customer meter reading and history; billing and logs of billing inquiries; solutions for payment options; accounting and adjustment processing and recording; service order scheduling and execution; credit and collections functions, including account holds and customer contact logs; meter and service line information; usage history; premise and marketing information; and variable customer information requirements. This CIS is compatible with Bay State's regulatory and operational obligations, and has absorbed through conversion most of the vital information contained in Bay State's legacy system. The CIS is an invaluable tool and is in use daily for customers, as it has been since 1999.

Q. Is that all that makes up the CIS investment?

A. No. Included in the investment is Bay State's cost of converting the legacy information (called CIS Pro-Edits) and the CIS Enhancements for meter to cash collections. The CIS enhancements for meter to cash improve the functionality of customer bill collection processes and supporting information, including an upgrade to the new release of the Customer Statement Format Design system, which supports Bay State's new bill format.

X. TRANSFER, SALE AND LEASE TRANSACTIONS

Q. Have there been sale and lease transactions that are reflected in Bay State's proposed rates?

A. Yes. The transactions involve the sale Bay State's propane peak shaving plant to EnergyUSA; the sale of LNG trailers to Transgas; and the sale and leaseback of Bay State's headquarters located in Westborough, MA.

Q. Were there transactions between Bay State and EnergyUSA?

A. Yes. There were a number of transactions between Bay State and EnergyUSA occurring primarily during 2002 and 2003, through which Bay State sold/leased propane related assets to/from EnergyUSA.[3] There was a 2001 sale of real estate in Brockton, Medway, West Springfield, along with property, structures, tanks and equipment in Taunton and Lawrence. There were leases entered into for land in Taunton and Lawrence. In 2001, Bay State sold propane tanks located in Medway, West Springfield, Taunton and Lawrence. Finally, there were a number of ancillary agreements that provided for leases between the parties.

Q. Are there ratemaking consequences to any of these transfers?

A. Only one, the sale of the propane tanks and related property. This transaction is identified in Mr. Skirtich's schedules and resulted in an identified $230,203 gain

[3] In mid-March 2003, EnergyUSA, divested itself of its propane business by selling all of its propane assets and assigning its propane contracts to an unaffiliated third party.

being passed through to customers. Each of the other asset sales/leases were at "fair market value." Net book value was determined to be a reasonable proxy of fair market value based on the fact that the propane assets had been duly offered for sale through a Request for Proposals ("RFPs"), to which no third-parties responded. The sale prices for the real property correspond to the net book value of each such asset on Bay State's books. The sale price of personal property was priced in aggregate.

Q. Does Bay State own the building and land on which its headquarters is based located at 300 Friberg Parkway, Westborough, Massachusetts?

A. No, it does not. It leases the building on a 15-year term for $1,122,180 annually, with escalators in the term of the lease. See, Exh. BSG/SHB-4 for the Westborough lease (in the Bryant Testimony). For ratemaking purposes, Bay State treats the lease payments as an operating expense.

Q. Did Bay State ever hold title to the building at 300 Friberg Parkway in Westborough?

A. Yes, it did. However, it sold the building and took a leaseback in 1997. The gain attributable to Massachusetts on the sale of property was $722,997. Consistent with Department precedent, Bay State proposes to flow the gain back to ratepayers over 5 years. See Exh. BSG/JES-1 at Schedule JES- 6, P. 7 of 20 (Skirtich).

XI. NECESSARY INDUSTRY-WIDE RESEARCH & DEVELOPMENT SUPPORT

Q. Is there any additional part of Bay State's proposed rates that you have been asked to support?

A. Yes. Bay State seeks recovery of costs incurred in the rate year associated with the Gas Technology Institute's Operations Technology Development ("OTD") and Environmental Issues Consortium ("EIC"). I will describe the ways supporting OTD and EIC can benefit our customers directly through efficiency, safety and future cost avoidance-related enhancements that Bay State cannot develop on its own.

Q. What is OTD?

A. Using the shared financial resources of the nation's natural gas utilities, OTD develops, tests, and implements new technology for the gas industry. OTD focuses on tools, equipment, software, processes, or procedures that will enhance safety, increase operating efficiency, reduce operating costs, and help maintain system reliability and integrity. The minimum annual cost of being an OTD program participant, given Bay State's size, is $250,000, and the total program costs are shared among participating natural gas companies. Bay State's participation in the OTD program will ensure its access to all OTD research and development. Participants determine the individual projects that will be undertaken each year by the OTD.

As a general matter, OTD projects are divided into the following six project categories: Pipe and Leak Location, Pipe Materials, Repair and Rehabilitation, Excavation and Site Restoration, Pipeline Integrity Management and Automation, Operations Infrastructure Support, and Environmental Science and Forensic Chemistry. These programs directly impact the safety, integrity, and least cost deliverability of natural gas in Massachusetts. Bay State has identified four specific OTD programs expected to benefit Bay State ratepayers directly, especially given the operational challenges Bay State faces associated with its aging steel infrastructure.

Q. Please list the four OTD programs and provide a brief overview of each.

A. The four programs include: (1) Remote Laser Leak Surveys; (2) Non-Interruptible Meter Change-Out Kits; (3) Alternative Methods to Pavement Cutting; and (4) Improving Crew Truck and Equipment Productivity. OTD is developing a program for remote laser leak surveys that will allow laser line-scan camera technology to survey distances of 30 meters for leaking gas underground while in a moving vehicle. Once commercially developed and operational in the field, this technology is expected to improve distribution system safety and reliability while reducing leak surveying costs borne by customers. Currently, Bay State surveys its system by mobile and walking technologies, but must be directly above the line to detect the presence of a leak. The Company believes an investment in developing this type of technology is important given the risk associated with leaks.

Q. Is this technology ready now?

A. No, not yet. OTD's research and development is needed to develop the technology for companies such as Bay State to be able to use in the field. These types of projects would be prohibitively expensive for an individual gas company to undertake.

Q. What other technologies are being developed by OTD?

A. OTD is developing a non-interrupted meter change-out kit that will permit LDCs to change out a meter without disrupting customer service and without having to make multiple appointment calls to gain re-entry into the customer premises to reinstate service and return gas-fired appliances to operation. This would avoid scheduling delays for repair crews and permit crews to focus on more significant on-site work orders, especially during heating months. Once developed, this initiative will allow the required 7-year changeout required by Massachusetts statute to be conducted more efficiently.

In addition, OTD is investigating alternative methods for asphalt and/or concrete pavement cutting, which is an activity engaged in constantly by Bay State to reach its facilities and which drives up construction costs and causes inconvenience and aggravation to the affected municipality. The goal of the research is to produce a prototype of equipment that will reach subterranean facilities with the least disruption to surface soil and toppings. A successful new cutting technology will reduce crew numbers, and the time and cost of in-street operations work, enhance operator safety and reduce the amount of traffic control-related expense, reduce noise (which may permit more efficient night work to be conducted in residential areas), improve customer relations and satisfaction with quicker, more efficient remediation of odor complaints as well as other operations and maintenance tasks, reduce damage associated with street openings, and therefore reduce the cost of street reconstruction and overlays. This is an important area of research for Bay State given the substantial investment it will be making to replace its unprotected steel infrastructure.

Q. Are there others?

A. Equipment and field crew productivity is being investigated with goals of increasing productivity, reducing operation and maintenance costs, increasing customer satisfaction with prompt and knowledgeable service and minimizing work-related injuries.

Q. Please explain the EIC program component of Bay State's request.

A. The EIC program will, among other things, be used to develop and enhance forensic tools and techniques capable of identifying whether Manufactured Gas Plants were the sole contributor to the presence of polynuclear aromatic hydrocarbons ("PAHs"), a hazardous material, in river sediment samples. Current forensic tools and techniques, including gas chromatography coupled with both flame ionization detectors [GC/FID] and mass spectrometry [GC/MS] provide "fingerprints" associated with given compounds. Also, gas chromatography coupled with isotope ratio mass spectrometry [GC/IRMS], which was developed by the petroleum industry to help distinguish between oil spilled from different tankers or refineries, now appears to be a good application in this context as well. However, these tools and techniques have not been used in the gas industry sufficiently to determine whether or not it will be useful, either alone or in conjunction with other techniques.

By using the forensic tools and techniques developed through this program, Bay State estimates that it will be able to avoid potential environmental remediation claims and related costs within the foreseeable future. For example, if Bay State were to reduce the volume of sediment that needed to be dredged by even a thousand yards, that would cover three years of research funding at the projected level. Given that PAHs are ubiquitous in urban river sediments, the savings will more than justify a decades' research into this issue.

After a quarter century of directing the clean up of hazardous materials, including byproducts from MGPs, from the Commonwealth's soil, groundwater and air, the Massachusetts Department of Environmental Protection ("MA DEP") is now turning its attention to cleaning up these same compounds in surface waters, especially sediments. The technology developed by the EIC program will assist in determining those locations where Bay State and its customers are responsible for remediation costs, and to defend against contribution in those locations where they are not.

XI. CONCLUSION

Q. Does this conclude your testimony?

A. Subject to my reserving my right to respond to issues that may be raised in the course of discovery or hearings, yes.